

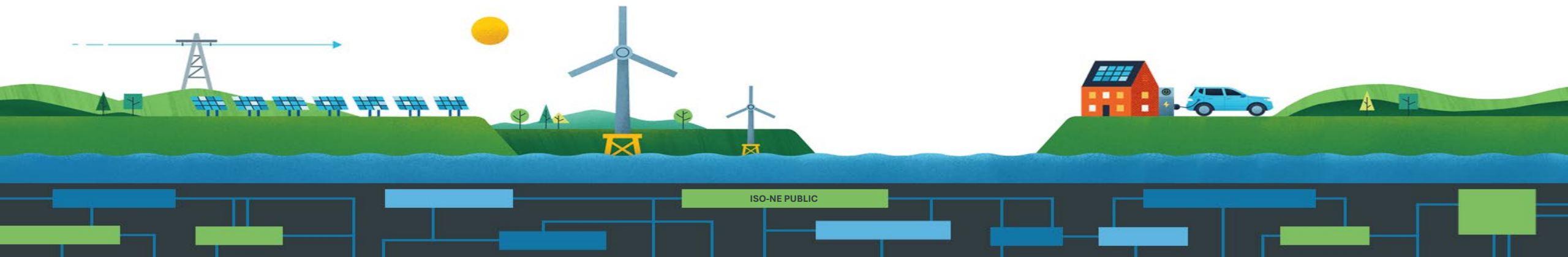


New England Large Load Show Cause Order (EL26-72)

Continued Discussion on Proposed Market Design and Settlement

Dennis Cakert

MARKET DEVELOPMENT



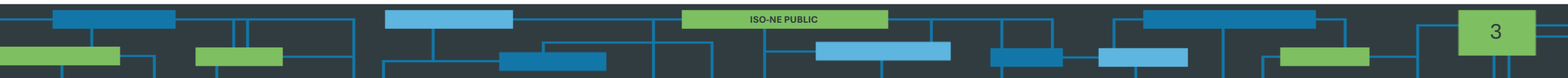
Proposed Effective Date: November 2026

Proposed Implementation Date: June 1, 2028

- This project covers the ISO's and Participating Transmission Owners' (PTOs) response to the [Federal Energy Regulatory Commission's \(FERC\) June 18, 2026 show cause order](#) (Order)
 - See the ISO's [conceptual design](#) presentation from August 18-19, 2026, and [detailed design](#) presentations from September 15, 2026
- This presentation reviews follow up items and incremental redlines related to market design and settlement:
 - Non-Firm Large Load Re-Dispatch Price
 - Behind-the-Meter Generation (BTMG)
 - Settlement

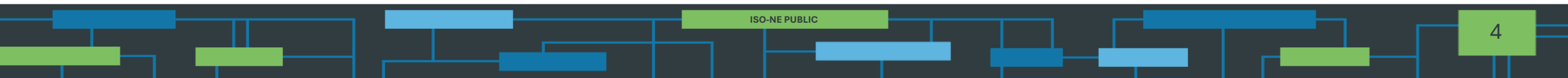
Additional Proposal Components

- Three additional presentations have been posted for the October 14 Joint TC/MC/RC meeting:
 - [Large Load Process Details](#) – Details of the Large Load Co-Located/Large Load Electrically Proximate Generator interconnection process, review of follow-ups from September meeting, proposal updates, and incremental Tariff redlines
 - [Operational Requirements](#) – Review of follow-ups from September meeting
 - [Cost Recovery Agreement \(CRA\)](#) – Introduction of draft CRA language and PTO OATT redlines
- The ISO and PTOs will continue to develop the proposal and associated Tariff redlines, incorporating feedback, through the [voting meeting](#)
 - The ISO will present its final proposal and associated Tariff language at the October 27 Joint TC/MC/RC meeting, focusing on any design refinements in response to stakeholder feedback and initial amendments

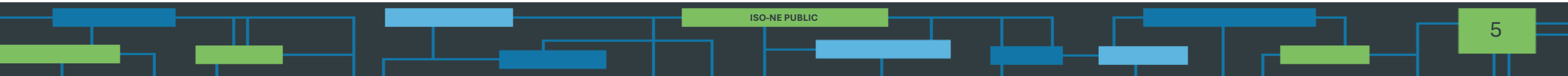


Background on Large Load Market Design and Settlement

- In September, ISO [proposed](#) market design and settlement rules to address several of the Order's considerations:
 - Cost shifting
 - Meter and settle Large Loads based on gross demand
 - Demand flexibility
 - Re-dispatch interim and non-firm service based on demand bids or a re-dispatch price
 - Co-Location
 - Allow interim and non-firm re-dispatch to be satisfied by energy supply from a Large Load Co-Located Generator (LLCLG) or Large Load Electrically Proximate Generator (LLEPG)
 - BTMG
 - New definition of BTMG and netting threshold for large loads
- The following slides further discuss concepts in response to stakeholder feedback

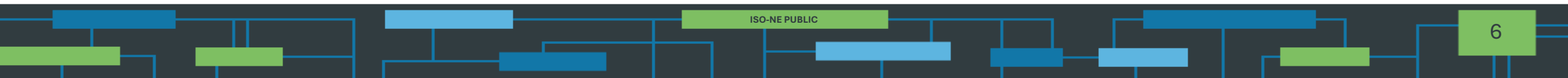


NON-FIRM LARGE LOAD RE-DISPATCH PRICE



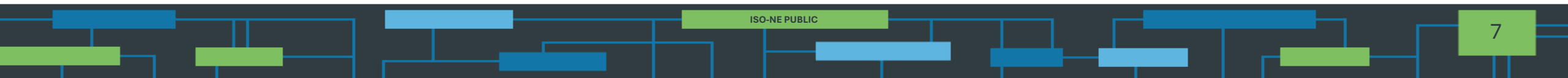
Background on Proposed Non-Firm Large Load Re-Dispatch Price

- A Large Load taking Interim Contract Demand Service (ICDS) or Non-Firm Contract Demand Service (NFCDS) receives unique benefits:
 - ICDS
 - Can withdraw from the system on a non-firm basis while any Large Load Network Upgrades and designated capacity needed to meet Firm Contract Demand Service are pending
 - NFCDS
 - Not required to identify and complete Large Load Network Upgrades for the same level of stressed system conditions as Regional Network Load or a Large Load taking Firm Contract Demand Service
 - Not required to bring new capacity supply
- To receive these benefits, a Large Load's non-firm service must be re-dispatchable in response to system conditions or price signals
 - Re-dispatch is necessary because the system does not have the network upgrades or capacity supply to serve the Large Load under all conditions as a result of the Large Load's election for NFCDS or ICDS
 - See Order at paragraphs 101-103
- Last month, ISO [introduced](#) the Non-Firm Large Load Re-Dispatch Price
 - When the Large Load's Locational Marginal Price (LMP) exceeds the re-dispatch price, the Large Load taking a non-firm transmission service is re-dispatched down
 - The re-dispatch price allows the Large Load taking non-firm service to be re-dispatched in response to transmission security or resource adequacy issues



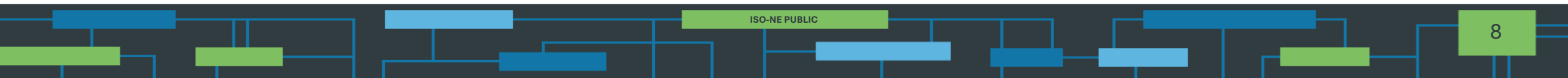
Rationale for Proposed \$250/MWh Non-Firm Large Load Re-Dispatch Price

- Addresses transmission security and resource adequacy risk accepted by Large Loads receiving non-firm service
 - \$250/MWh allows re-dispatch of a Large Load taking non-firm service in response to a transmission security event or a Capacity Scarcity Condition (CSC)
- Reduces cost shifting and addresses affordability
 - The Order directs ISO-NE to reduce cost shifting across several markets
 - The Commissioners strongly emphasize consumer protection and affordability (see appendix)
- Aligns with the penalty factor for replacement reserves
 - Conceptually, since the region is willing to forgo replacement reserves (a reliability service) at \$250/MWh, it is reasonable to forgo service to non-firm Large Loads at \$250/MWh
- Historically, LMP exceeds \$250/MWh in ~1% of hours
 - See appendix for additional details
- Use of a static number allows for a timely and streamlined implementation



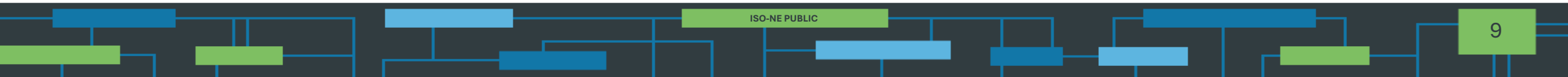
Alternative Re-Dispatch Prices

- At the September meeting, stakeholders suggested that ISO evaluate the following alternative re-dispatch prices:
 - A reserve-based re-dispatch price, instead of energy-based
 - A dynamic re-dispatch price that is indexed to fuel costs
- The following slides further explore these alternatives



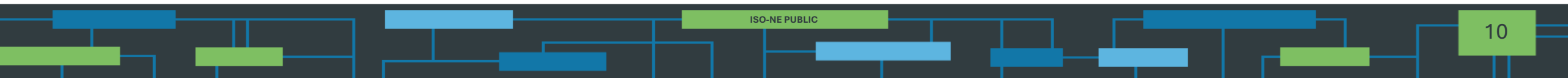
Alternative 1: Reserve-Based Re-Dispatch Price

- Stakeholders noted that reserve prices may be a more accurate indication of resource adequacy risk
 - For example: With an LMP-based re-dispatch price, the LMP could be high due to fuel costs, but there may not be a resource adequacy risk
 - See appendix for data on reserve constraints during intervals with LMP > \$250/MWh
- ISO has concerns with a reserve-based re-dispatch price
 - First, it does not address transmission security risks
 - Reserve prices can be \$0 during a transmission security event
 - See appendix example 3B
 - Second, it is a novel design that, to the best of ISO's knowledge, has never been used
 - If the region relies on this design in the November 2026 filing, it poses a risk that it is not feasible in practice, or at least not feasible by the implementation date



Alternative 2: Dynamic Re-Dispatch Price

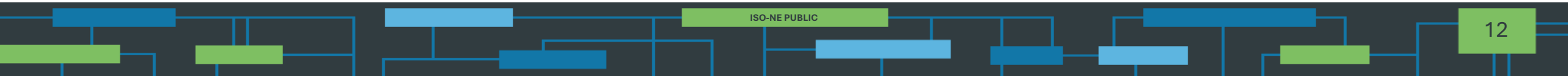
- Stakeholders noted that a dynamic re-dispatch price, such as a price indexed to fuel costs, would more accurately account for conditions where prices are higher but there is not a resource adequacy risk
- ISO agrees there is precedent for dynamic price thresholds in ISO markets:
 - Day-Ahead Ancillary Services (DASI) Strike Price
 - Demand Response Threshold Price (DRTP)
- ISO has concerns with a dynamic re-dispatch price:
 - First, the DASI Strike Price and the DRTP are substantial design and implementation efforts
 - Undertaking this type of design may be better suited for a post-implementation adjustment once the region gains operational experience with large loads
 - Second, it could result in greater cost shifting and affordability concerns
 - If LMP increases due to fuel costs, Large Loads taking non-firm service would not be re-dispatched



ISO is Open to Stakeholder Amendments on the Proposed Non-Firm Large Load Re-Dispatch Price

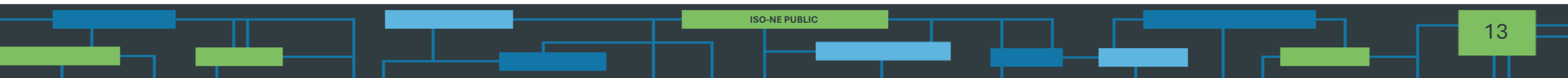
- Any stakeholders interested in proposing an amendment on the Non-Firm Large Load Re-Dispatch Price should submit to the TC Secretary (jmacura@iso-ne.com) by October 21, 2026
- ISO will evaluate amendments based on the following considerations:
 - How the price addresses transmission security and resource adequacy risk as assumed by the Large Load taking non-firm service
 - How the price addresses cost shifts and affordability for other consumers
 - Whether the price can be implemented by June 1, 2028
 - Broad stakeholder support
- ISO is open to continued discussion on the re-dispatch price in 2027

BEHIND-THE-METER GENERATION (BTMG)



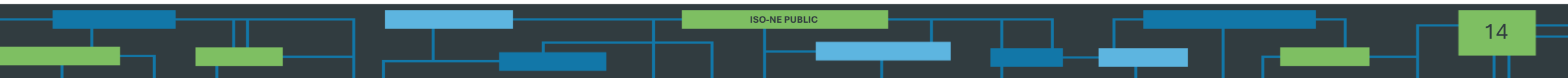
BTMG Definition and Netting Threshold

- Following the September meeting, stakeholders requested that the ISO clarify the definition of BTMG
 - Stakeholders noted that the BTMG must be at least separately metered at the facility level for purposes of calculating the Large Load's gross demand
- ISO agrees and proposes to clarify the BTMG definition:
 - “...and is not separately metered *in wholesale markets* from the end-use customer load”
- For example, if a 100 MW Large Load has a 10 MW BTMG, they can either:
 1. Report 100 MWh gross demand for the Large Load and the 10 MWh from the BTMG will act as a load reducer in the metering domain
 2. Report 100 MWh gross demand for the Large Load, register the BTMG as a generator in the wholesale market, and report 10 MWh of energy supply for the generator

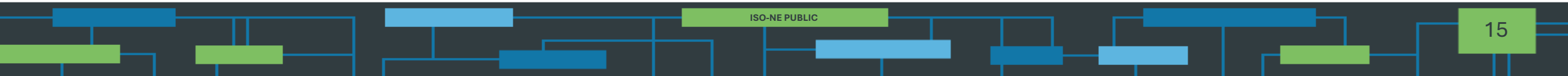


Incremental Redlines for BTMG

Section	Tariff or Manual Change	Reason for Change
I.2.2 - Behind the Meter Generation	“generation directly connected to end-use customer load and located behind the end-use customer’s Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, and is not separately metered <i>in wholesale markets</i> from the end-use customer load”	Clarify that the separate metering requirement applies to wholesale markets



SETTLEMENT



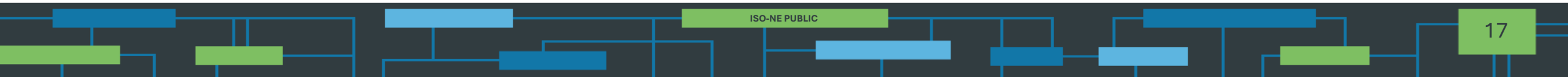
Settlement for Transmission and Reliability Services for Non-Firm Large Loads Aligns with Other Non-Firm Loads

- At the September meeting, stakeholders noted that a non-firm Large Load may be re-dispatched during the local network's monthly peak, which would reduce the large load's charges for transmission and reliability services
 - For background, cost allocation for transmission and reliability services is based on usage during the local network's monthly peak hour
 - Though most monthly peaks occur with LMP less than \$250/MWh, if LMP exceeds \$250/MWh during the local monthly peak, the non-firm large load will be re-dispatched down and therefore charged less for transmission and reliability services
- ISO believes the proposed settlement design for non-firm Large Loads aligns with the study assumptions, and the basis of transmission services, for non-firm Large Loads and with the existing settlement design for other non-firm loads
 - Large Load system impact studies allow non-firm Large Load re-dispatch at shoulder and peak load levels to resolve thermal overloads without the need for network upgrades
 - Storage resources with demand bids $\leq$ \$250/MWh are dispatched down during monthly peaks when LMP exceeds \$250/MWh and are therefore charged less for services

Redlines for Open Access Transmission Tariff (OATT)

Schedules 1, 2, 8, 16, and 17

- At the September meeting, ISO noted redlines for OATT Schedule 1, 2, 8, 16, 17 would be posted for the October 14 TC meeting
- The redlines for schedules 1, 2, 16, and 17 are posted with today's meeting materials and summarized on the next slide
- ISO proposes not to include Large Loads in Schedule 8 settlement
 - Schedule 8 is for Through or Out Service (TOUT), which involves exporting power to load outside of ISO New England service territory
 - Schedule 8 does not apply to Regional Network Loads and should not apply to Large Loads either, since they are both loads within ISO New England service territory



Redlines for OATT Schedule 1

Section	Tariff Change
Introduction	Establish that Large Load Transmission Customers are charged for this service
Introduction	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62
II.A - Surcharge	Establish that Large Load Transmission Customers are charged for this service
II.A - Surcharge	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62
II.C - Rate	Establish that demand for Large Load Transmission Customers is used in the rate calculation for this service

Redlines for OATT Schedule 2

Section	Tariff Change
Introduction	Establish that this service is supplied to Large Load Transmission Customers
III – Determination and Allocation of VAR Service Charges	Establish that Large Load Transmission Customers are charged for this service
III – Determination and Allocation of VAR Service Charges	Establish that demand for Large Load Transmission Customers is used in the rate calculation for this service
III – Determination and Allocation of VAR Service Charges	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62

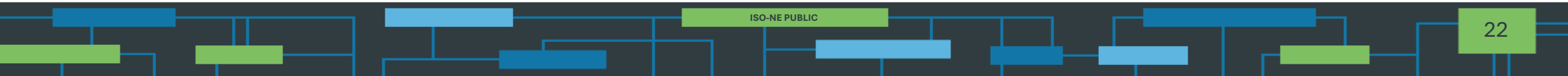
Redlines for OATT Schedule 16

Section	Tariff Change
Introduction	Establish that this service is utilized by Large Load Transmission Customers
Introduction	Establish that demand for Large Load Transmission Customers is used in the rate calculation for this service
Introduction	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62
6. Monthly Blackstart Service Charge	Establish that Large Load Transmission Customers are charged for this service
6. Monthly Blackstart Service Charge	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62

Redlines for OATT Schedule 17

Section	Tariff Change
Introduction	Establish that Large Load Transmission Customers are invoiced for this service
3. Invoicing and Collection of IROL-CIP Costs by ISO	Establish that Large Load Transmission Customers are invoiced for this service
3.2 IROL-CIP Charges	Establish that demand for Large Load Transmission Customers for this service is determined in OATT Section II.62

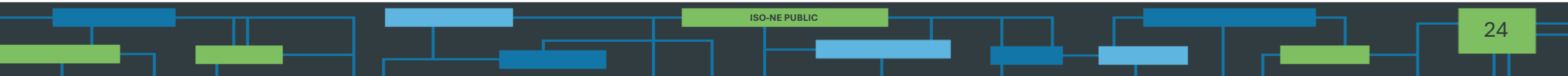
OTHER INCREMENTAL REDLINES



Incremental Redline to III.1.10.5A

Section	Tariff Change	Reason for Tariff Change
III.1.10.5A(b)(ii)	"Use energy supply from a Large Load Co-Located Generator or Large Load Electrically Proximate Generator to achieve re-dispatch requirements for Interim Contract Demand Service and/or Non-Firm Contract Demand Service pursuant to Section III.1.10.5A(c)(iii)."	Use the full defined term

CONCLUSION AND NEXT STEPS



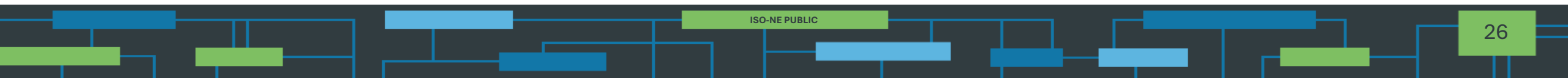
Conclusion and Next Steps

- ISO proposes market design and settlement rules to integrate Large Loads
- The design addresses the Order's considerations on cost shifting and affordability, demand flexibility, co-location, and BTMG
- This presentation responded to follow up requests from stakeholders at the September 14 meeting and summarized incremental tariff redlines
- This presentation, combined with the accompanying Large Load Process Details and Operational Requirements presentations, cover all ISO proposed Large Load design details and Tariff redlines needed to respond to the June 18, 2026 show cause order have been presented
- Feedback on the proposed market design and settlement should be submitted to the TC Secretary (jmacura@iso-ne.com) by October 19, 2026
 - Any amendments and associated redlines should be submitted to the TC Secretary by October 21, 2026

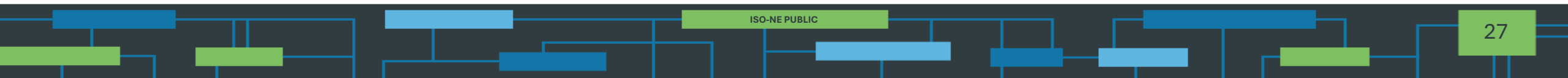
Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee (MC Invited) July 16, 2026	Overview of abeyance request, timing for Section 205 process, and informational filing content
Joint Reliability and Transmission Committee (MC Invited) August 18-19, 2026	Overview of conceptual design proposal for Section 205 filing
Joint Transmission, Markets, and Reliability Committee September 15, 2026	Review of details on proposed Large Load study process, operational requirements, market design and settlements, introduction to CRA and initial Tariff redlines
Joint Transmission, Markets, and Reliability Committee October 14, 2026	Review of remaining design details and incremental updates to the ISO and PTO AC proposals based on stakeholder feedback, including any incremental Tariff language; Introduction of stakeholder amendments
Joint Transmission, Markets, and Reliability Committee October 27, 2026	Review of final proposals and associated Tariff language, focusing on any design refinements in response to stakeholder feedback and initial amendments; Review of stakeholder amendments
Transmission Committee November 3, 2026	Vote on TC jurisdictional redlines associated with ISO and PTO AC proposals, and any stakeholder amendments
Reliability Committee November 3, 2026	Vote on RC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Markets Committee November 3, 2026	Vote on MC jurisdictional redlines associated with ISO proposal, and any stakeholder amendments
Participants Committee* November 12, 2026	Vote on ISO proposal and any stakeholder amendments

*PTO AC action will be required ahead of the PC vote and FERC filing

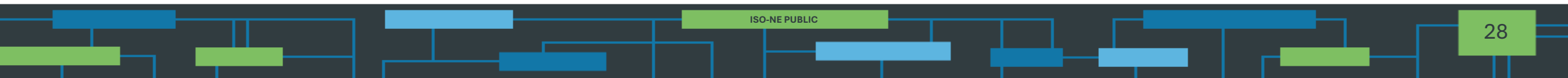


Questions



APPENDICES

- Commissioner Statements on Affordability
- Historical \$250/MWh LMPs by Month from 2021-2025
- Historical Binding Reserve Constraints Compared to RT Hub LMP from 2021-2025
- Examples of Transmission Security Risk from Non-Firm Large Loads

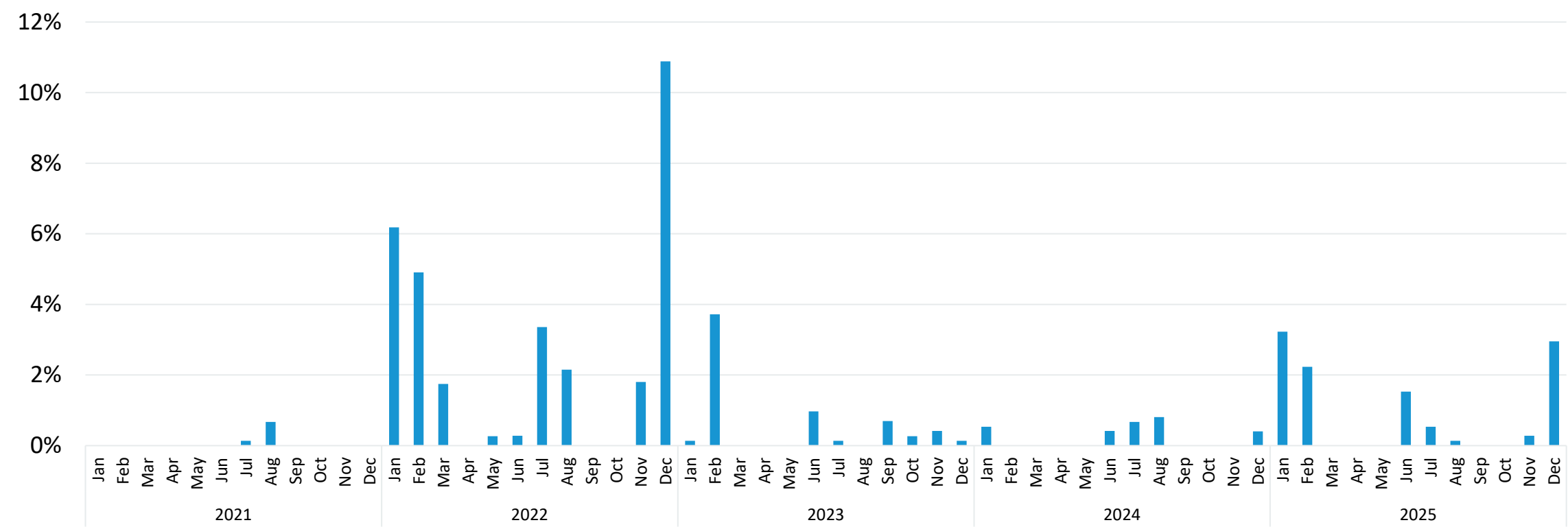


Commissioner Statements on Affordability

- Commissioner Rosner
 - "Today's orders are aimed at ensuring that the grid remains reliable and affordable for *all* customers, especially residential customers... The door remains open to other creative, regionally-specific ideas to protect consumers. If there are other ways to accomplish that goal, I welcome those proposals."
- Commissioner See
 - "Affordability must be at the forefront as we protect consumers from unnecessary costs in a time of rising demand... we need to pull all the levers we have to keep rates fair and transparent... I welcome bold proposals to keep affordability central."
- Commissioner Chang
 - "The FPA is fundamentally a customer protection statute, and the Commission has an obligation to ensure that the rates that wholesale and transmission customers pay are just and reasonable... It is therefore important that the resulting regulatory and rate design are not limited to a pre-defined solution set, and that parties provide the Commission with comprehensive records outlining various and innovative approaches to protect customers."
- Commissioner LaCerte
 - "I expect ISO-NE to design proposals in response to this show cause order that dovetail with the efforts on the retail side to implement the Ratepayer Protection Pledge, protect customers, and ensure that large loads cover the costs they incur to integrate with the grid... Affordability remains a top concern as we proceed forward... The stakes for reliability, for affordability, and for the American ratepayer could not be higher."

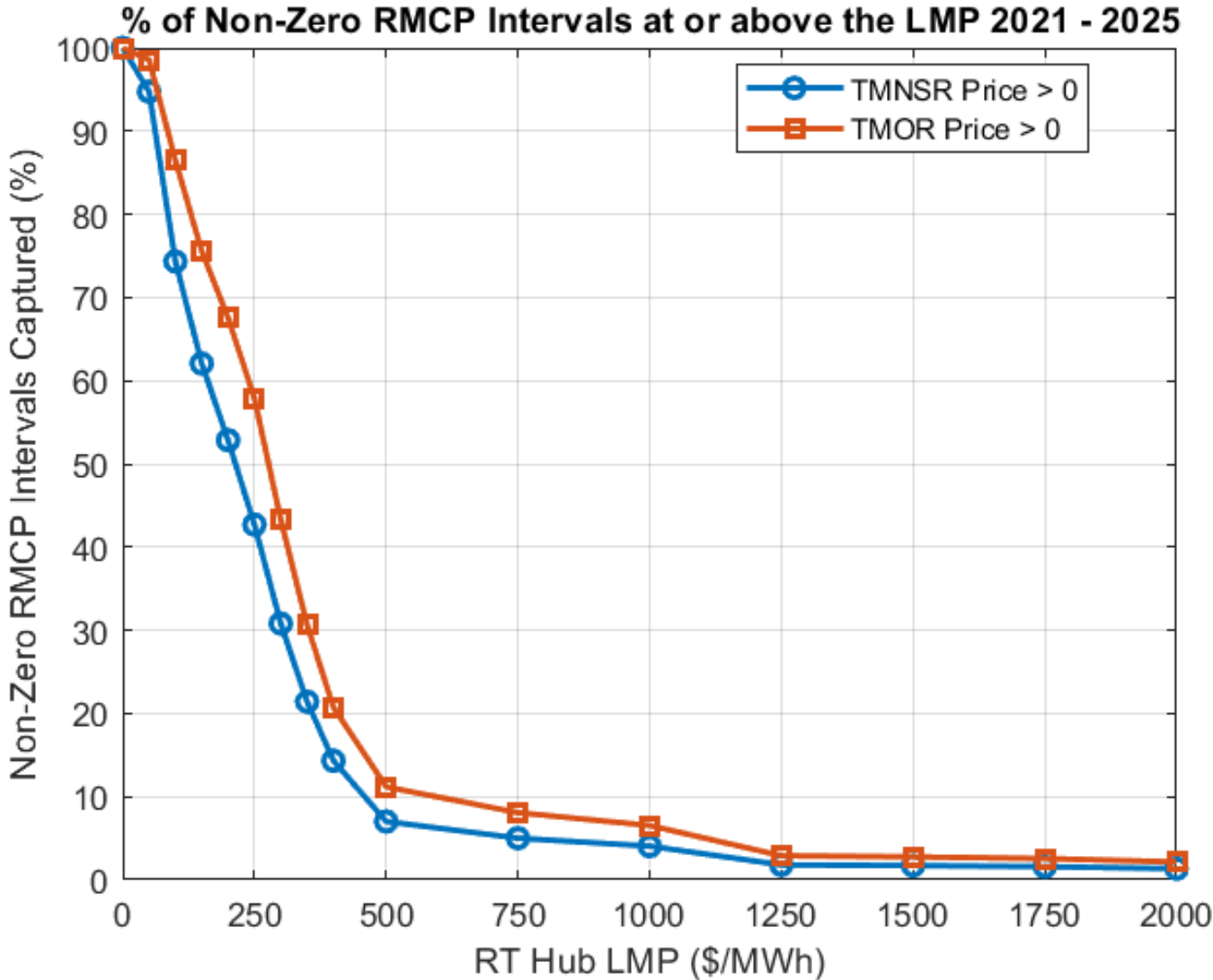
Historical Hourly RT Hub LMPs > \$250/MWh by Month

- The chart below shows percent of hours in each month from 2021-2025 where hourly RT Hub LMP exceeded \$250/MWh



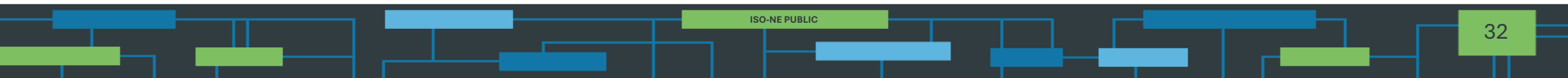
Historical Binding Reserve Constraints Compared to RT Hub LMP from 2021-2025

- At the September 14 meeting, stakeholders requested data on how often reserve constraints were binding at \$250/MWh LMPs
- The graph on the right shows the percent of intervals with binding reserve constraints that occur above a given RT Hub LMP
- For example: roughly 40% of intervals with a binding TMNSR constraint and 60% of intervals with a binding TMOR constraint occur at LMPs above \$250/MWh
- In other words, a re-dispatch price of \$250/MWh would result in re-dispatch of non-firm Large Loads in roughly half of the intervals with binding reserve constraints

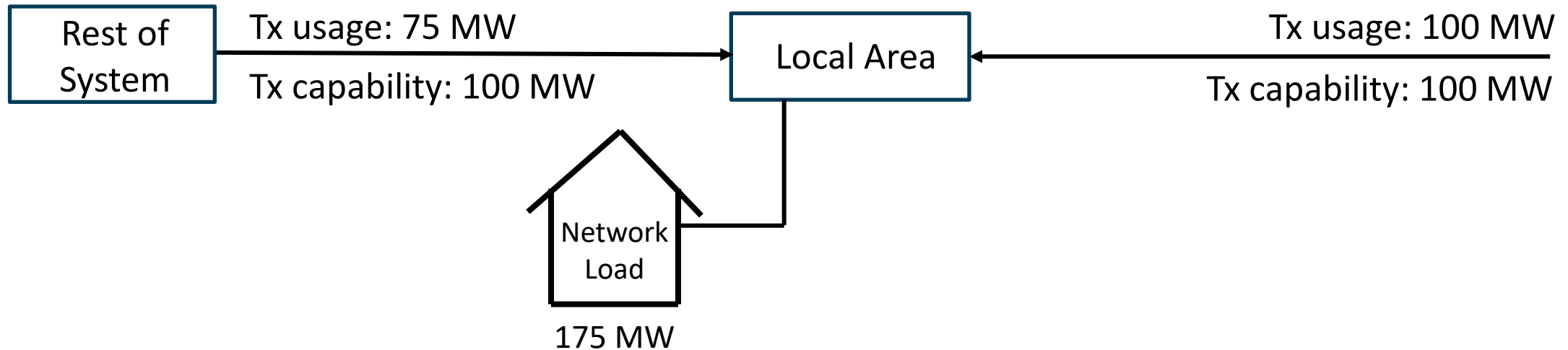


Transmission Security Risk: Example Overview and Assumptions

- The following slides demonstrate how a non-firm Large Load can create transmission security risks
- For the examples, assume the following characteristics
 - The system-wide marginal generator is \$50/MW
 - The local area Network Load is 175 MW
 - The local area transmission capability is 200 MW
- Example 1 has no Large Loads
- Example 2 has a 50 MW Large Load with firm service
- Example 3 has a 50 MW Large Load with non-firm service
 - 3A shows how an LMP-based re-dispatch price resolves transmission security risk
 - 3B shows how a reserve-based re-dispatch price does not resolve transmission security risk

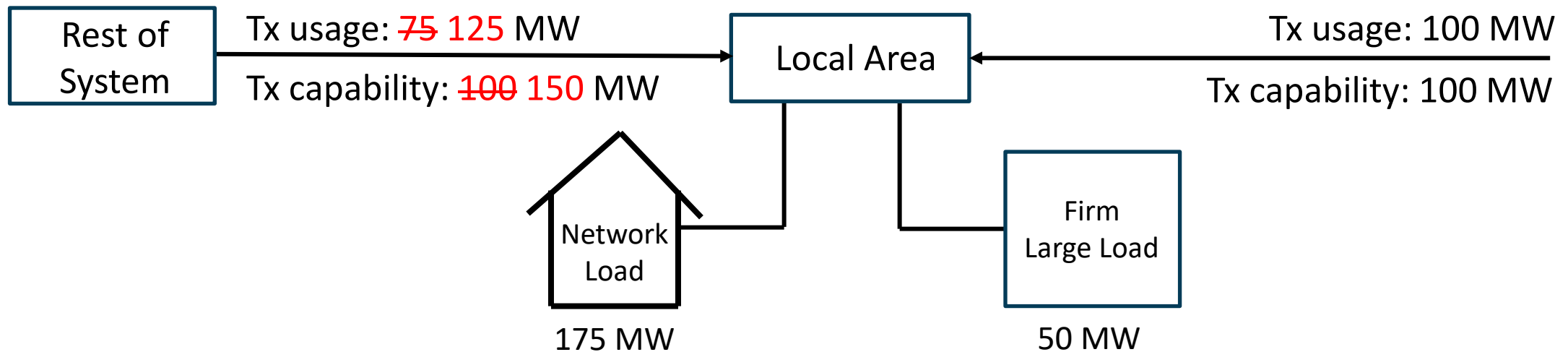


Example 1: No Large Loads



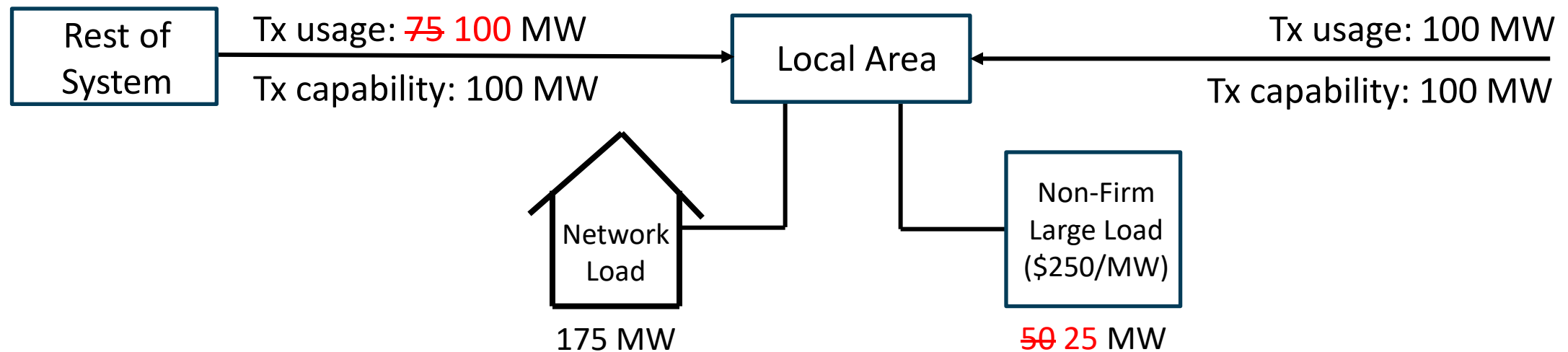
Example 1: There is adequate transmission to serve the network load. LMP in the local area is set by the system-wide marginal generator at \$50/MWh.

Example 2: 50 MW Large Load with Firm Service



Example 2: A 50 MW Large Load with firm service completes network upgrades, which increase transmission capability in the local area from 200 MW to 250 MW. There is adequate transmission to serve both the network load and firm large load. LMP in the local area is set by the system-wide marginal generator at \$50/MWh.

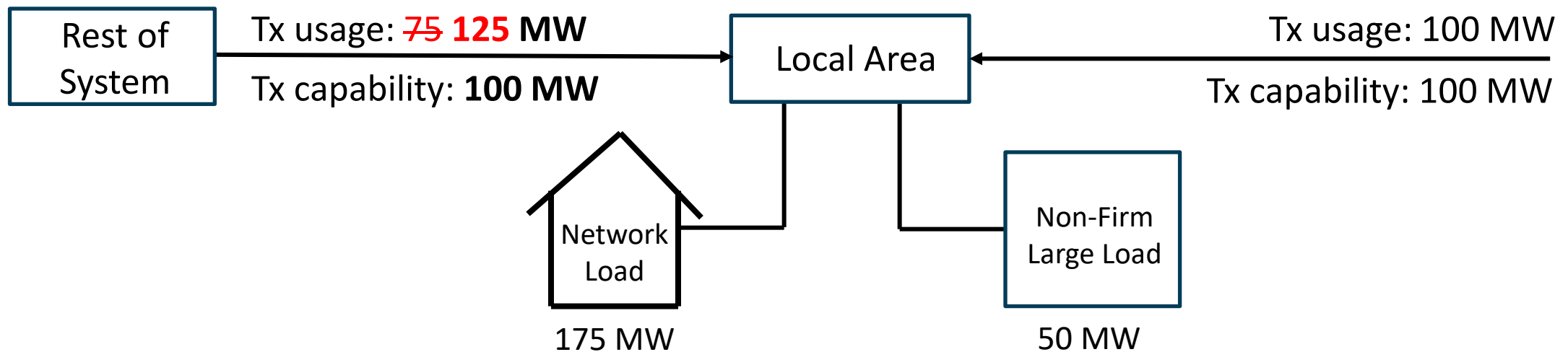
Example 3A: LMP-Based Re-Dispatch Price



Example 3A: A 50 MW non-firm Large Load does not complete network upgrades. Load in the local area exceeds transmission capability. The least cost solution is to re-dispatch the non-firm Large Load down by 25 MW. LMP is \$50/MWh for the system and \$250/MWh for the local area.

Example 3B: Reserve-Based Re-Dispatch Price

Background: in September, stakeholders suggested ISO evaluate a re-dispatch price that uses a reserve-based price, instead of LMP-based. See slide 9 for additional details. This example shows how a reserve-based price does not resolve transmission security risk.



Example 3B: A 50 MW non-firm Large Load does not complete network upgrades. Load in the local area exceeds transmission capability, but the reserve price is \$0/MWh and there is no market-based solution. The local area enters OP-7 and OP-19.